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NATIONAL ENERGY EMISSIONS AUDIT

National Energy Emissions Audit - Electricity Update

August 2017

Providing a comprehensive, up-to-date indication of key electricity trends in Australia

Author: Hugh Saddler

Reviewer: Ben Elliston

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Level 1, Endeavour House, 1 Franklin St
Canberra, ACT 2601
Tel: (02) 61300530
Email: mail@tai.org.au
Website: www.tai.org.au

Introduction

Welcome to the August 2017 issue of the *NEEA Electricity Update*, the companion publication to the *National Energy Emissions Audit Report*. The *Electricity Update* is published monthly and presents data on electricity demand, electricity supply, and electricity generation emissions in the National Electricity Market (NEM). Each issue of *Electricity Update* contains a more detailed discussion of one or two particular topics relating to the electricity system which have assumed particular importance in the period prior to publication. The July issue examined how higher generation costs are contributing to rising retail prices of electricity for consumers. In this issue the topic focuses on the network costs component of retail prices, with a look back at how and why this has increased over the past ten years.

Methodology

All data are reported as annual moving averages. This approach removes the impact of seasonal changes on the reported data. Annualised data reported in *NEEA Electricity Update* will show a month on month increase if the most recent monthly quantity is greater than the quantity in the corresponding month one year previously. Most data are presented in the form of time series graphs, starting in June 2011, i.e. with the year ending June 2011. Some graphs start in June 2008. These starting dates have been chosen to highlight important trends, while enhancing presentational clarity.

Defining the particular meaning of the various terms used to describe the operation of the electricity supply system will help in understanding the data discussed in this and all other issues of *NEEA Electricity Update*.

Demand, as defined for the purpose of system operation, includes all the electricity required to be supplied through the grid level dispatch process, operated by AEMO. This includes all the electricity delivered through the transmission grid to distribution network businesses, for subsequent delivery to consumers. It also includes energy losses in the transmission system and auxiliary loads, which are the quantities of electricity consumed by the power stations themselves, mostly in electric motors which power such equipment as pumps, fans, compressors and fuel conveyors. Auxiliary loads are very large: in 2011 they amounted to 6.3% of total electricity generated and currently about 5.6%. Most of this load is at coal fired power stations, where it can be as high as 10% of electricity generated at an old brown coal power station and 7% at a black coal fired power station. Auxiliary loads are much lower at gas fired power stations, and close to zero at hydro, wind and solar power stations. Both demand and generation, as shown in the *Electricity Update* graphs, are adjusted by subtracting estimates of auxiliary loads. Thus demand, as shown, is equal to electricity supplied to distribution networks (and a handful of very large users that are connected directly to the transmission grid) plus transmission losses.

Generation is similarly defined to include only electricity supplied by large generators connected to the transmission grid. It does not include electricity generated by rooftop PV installed by electricity consumers, irrespective of whether that electricity is used on-site ("behind the meter") by the consumer, or exported into the local distribution network. From the perspective of the supply system as a whole, the effect of this generation, usually termed either "embedded" or "distributed" generation, is to reduce the demand for grid supplied electricity below the level it would reach without such distributed generation. That effect can be clearly seen in the regular total generation graph; the gap between the red line – electricity sent out to the grid from large grid connected power stations – and the yellow line – that electricity plus estimated electricity generated by distributed solar systems – is the electricity supplied by those systems, which for the year ending June 2017 was about 5.5 TWh p.a., equivalent to nearly 3% of the combined total.

Key points

NEM electricity generation emissions down slightly

Total emissions from electricity generation in the NEM fell quite sharply in the year to June 2017, compared with the year ending just one month earlier.

Brown coal generation continuing down, with Queensland black coal generators the main beneficiaries

Supply trends reported in the July issue continued, with coal generation in Queensland and NSW both up, together with net exports from Queensland to NSW and from NSW to Victoria.

Wind generation rebounds to a record level in July

In contrast to June, July was a very strong month for wind generation, with the highest ever monthly total generation1.36 TWh, recorded. Particularly high levels of generation were achieved in SA, where the month average capacity factor was 49% and generation was equal to 47.5% of all grid electricity generated in the state.

Total NEM demand down and WA demand also down

Total demand for electricity In the NEM in the year to July 2017 was virtually the same as in the year to June, but continued to decrease in WA.

Network costs continue as the largest component of retail prices

Until this year, the large increases in retail electricity prices were mainly caused by higher network costs, particularly in NSW and Queensland. A look back over network business expenditure and revenue over the past ten years shows that electricity consumers are continuing to pay for past policy failures in the regulation of monopoly network businesses.

Generation and emissions

Total annual emissions from electricity generation in the NEM fell sharply from June to July 2017, just under 0.6 Mt CO_2-e, equal to 0.3% (see Figure 1), while total generation was almost unchanged (see Figure 3). Figure 1 also shows that rooftop solar PV installed by both residential and commercial electricity consumers, which increases gradually month by month, supplied an additional 3% of consumption.

Figure 1

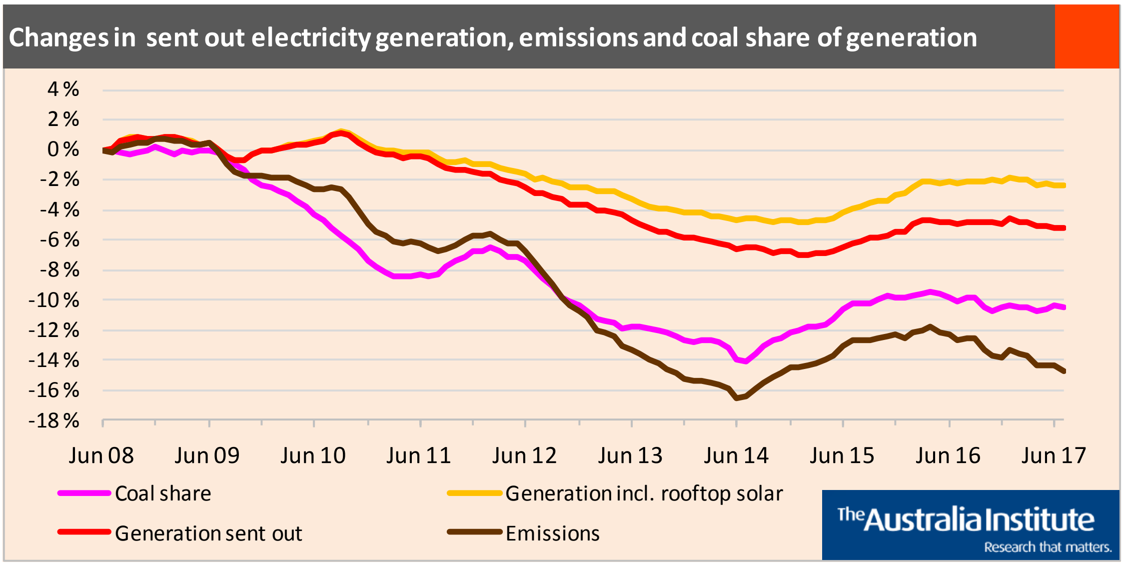


Figure 1 also shows that the divergence between coal share and total emissions in the past three months is continuing. The closure of Hazelwood power station at the end of March has led to a restructuring of electricity flows between the three main regions of the NEM, reflecting the changed relationship between available generation capacity and the short run marginal cost of generation.

This effect can be seen most clearly in July, which is invariably the month with the highest total electricity consumption in all states except Queensland. (Over the year, most households and businesses outside the tropics use considerably more electrical energy for space heating than for space cooling, although the peak demand for cooling is higher than the peak demand for heating everywhere except Tasmania.) During July, 10% of the electrical energy consumed in NSW was, in net terms, imported from Queensland, while 2% of the electricity consumed in Victoria was imported, in net terms, from NSW.

Overall, therefore, a large quantity of electricity flowed from Queensland to NSW, and a smaller quantity flowed on to Victoria. The flow from NSW to Victoria would have been higher, but for the fact that very high levels of wind generation meant that net imports from SA supplied a further 3% of Victoria's electricity consumption for the month. More commonly, at least up to now, SA is a net importer from Victoria. For the NEM as a whole, lower brown coal generation, because of the closure of Hazelwood, was almost precisely matched by the increase in less emissions intensive black coal generation. Hence, while the coal share of total generation was unchanged, emissions went down, as can be seen in Figure 2.

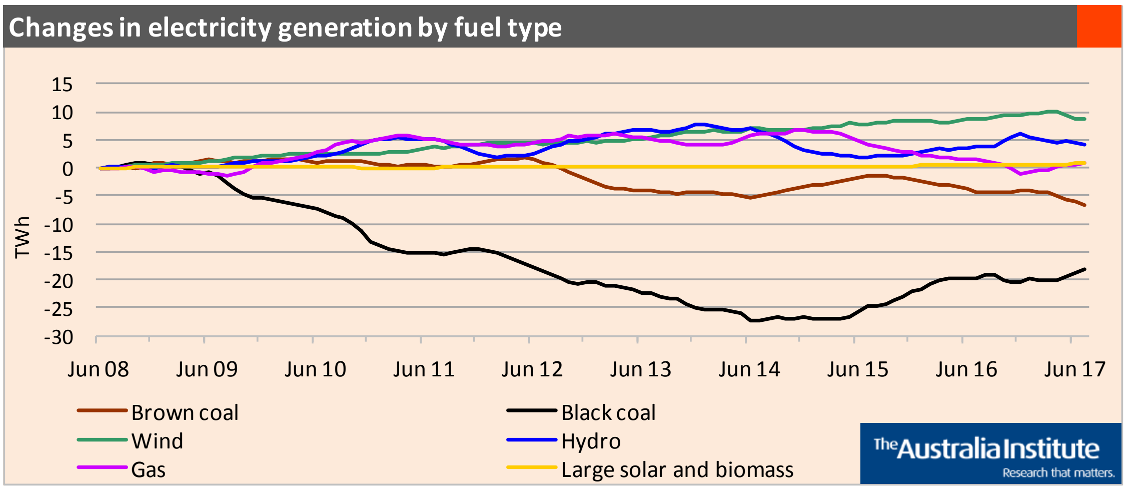
During July, the total availability and total electricity supplied from the three Victorian brown coal generators were effectively identical, at 78% of registered capacity. In other words, throughout the month 100% of every MW bid into the market by the three brown coal power stations was dispatched. By contrast, for Queensland black coal generators as a whole, 91% of available capacity was dispatched, while for the NSW black coal generators the proportion of available capacity dispatched was only 82%. These ratios correspond to the relative fuel costs of the three groups of generators: the lower the fuel cost, the lower the price at which a generator will bid, all else being equal, and hence more likely it will be that all bids get dispatched. Victorian brown coal generators on average have the lowest fuel costs, followed by the Queensland black coal generators, with the NSW black coal generators having the highest average fuel costs.

Of the NSW power stations, Liddell, the oldest, scheduled to be closed in 2022, had the lowest ratio of dispatched to available capacity. Queensland has the most modern and efficient coal fired power stations in Australia. Three plants – Callide Power Plant, Milmerran and Kogan Creek – have been commissioned since 2001 and all use super-critical technology. Together they account for 30% of Queensland's coal generation capacity. The most modern – or least old – stations in NSW and Victoria, respectively Mount Piper and Loy Yang B, are nearly ten years older, i.e. 24 and 23 years respectively.

These characteristics of the current fleet of coal fired power stations suggest that a new transmission line linking NSW and SA might make a valuable contribution to strengthening the reliability and security of the NEM as the transition away from coal and towards wind and solar generation develops.

The mirror image changes in black and brown coal generation are clearly shown in Figure 2. The effect of the Hazelwood closure was also seen in Victorian gas generation, which increased by 18% from June to July, and has more than doubled since January. The increase was large enough to more than offset decreased gas generation in other states, resulting in a small increase for the NEM as a whole. Figure 2 also shows a modest decrease in hydro generation, which was attributable to decreases in both Tasmania and the Snowy. This is a common seasonal pattern for both systems; generation is reduced during winter and spring to allow storages to replenish, so that more electricity can be generated during the summer months, when wholesale prices at peak demand periods are usually at their highest.

Figure 2



After sharp falls in both May and June, total annual wind generation increased slightly in July. There was a particularly large increase in wind generation in SA, both because of the commissioning of Stages 1 and 2 of the large Hornsdale windfarm over the past year (both contracted by the ACT Government), and because of the exceptionally windy weather right across the state. Total generation in SA during the month of July was the highest ever monthly figure, and 14% higher than any previous month. Monthly wind generation in Victoria was also a record in Victoria, in significant part because of the commissioning of the large Ararat wind farm, also contracted by the ACT government, during the past year.

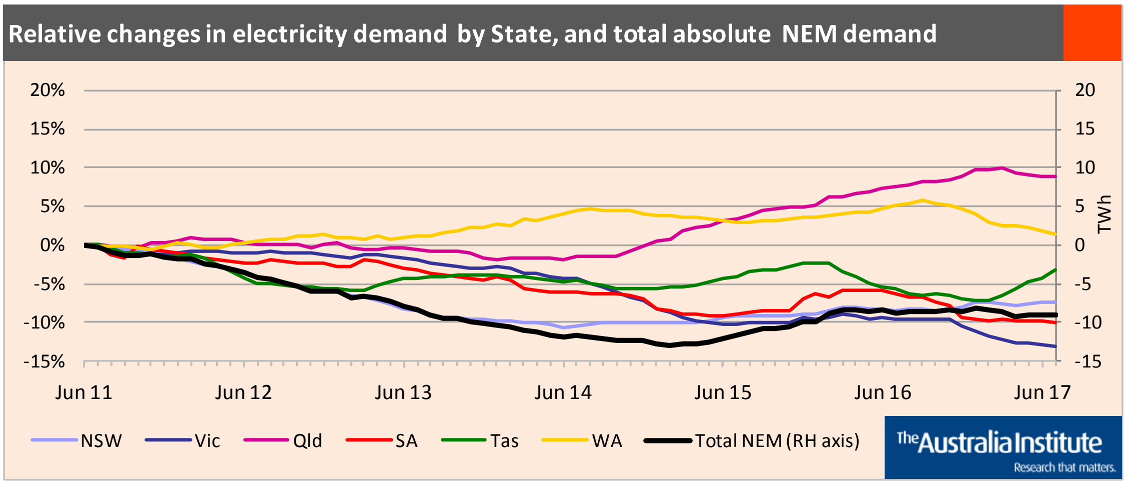
Monthly generation in SA would have been even higher, but for the curtailment by AEMO, in its role as system operator, of output from several windfarms. This was imposed, under new system security procedures, at times when gas generation within the state had fallen to levels which were considered to make the system insecure in the event of a major disruption, such as a failure of the Heywood interconnector.

Despite the curtailments, the average capacity factor for wind generators in SA during the whole of July was 49%. Wind generation exceeded 52% of total electricity supplied in SA through the NEM, i.e. excluding rooftop solar. When solar is added, the renewable share of total supply during the month reached an average level of 59%. Total wind generation exceeded total state demand for 48 hours across seven separate days during the month, by an average of over 7%.

Demand

Figure 3 shows the relative changes, since the year ending June 2011, in total annual demand for electricity in each of the five regions of the NEM, and also in the WA SWIS (South West Interconnected System), which is the main electricity grid in the state. It also shows the absolute change in total demand in the NEM as a whole. Demand in Queensland has levelled off, confirming that the mix of factors affecting electricity demand in the other NEM states over the past year and a half are also now operating in Queensland. Electricity demand in WA continued to decrease, while total NEM demand stayed almost constant, as it has for the past two years.

Figure 3



Electricity prices: Part 2

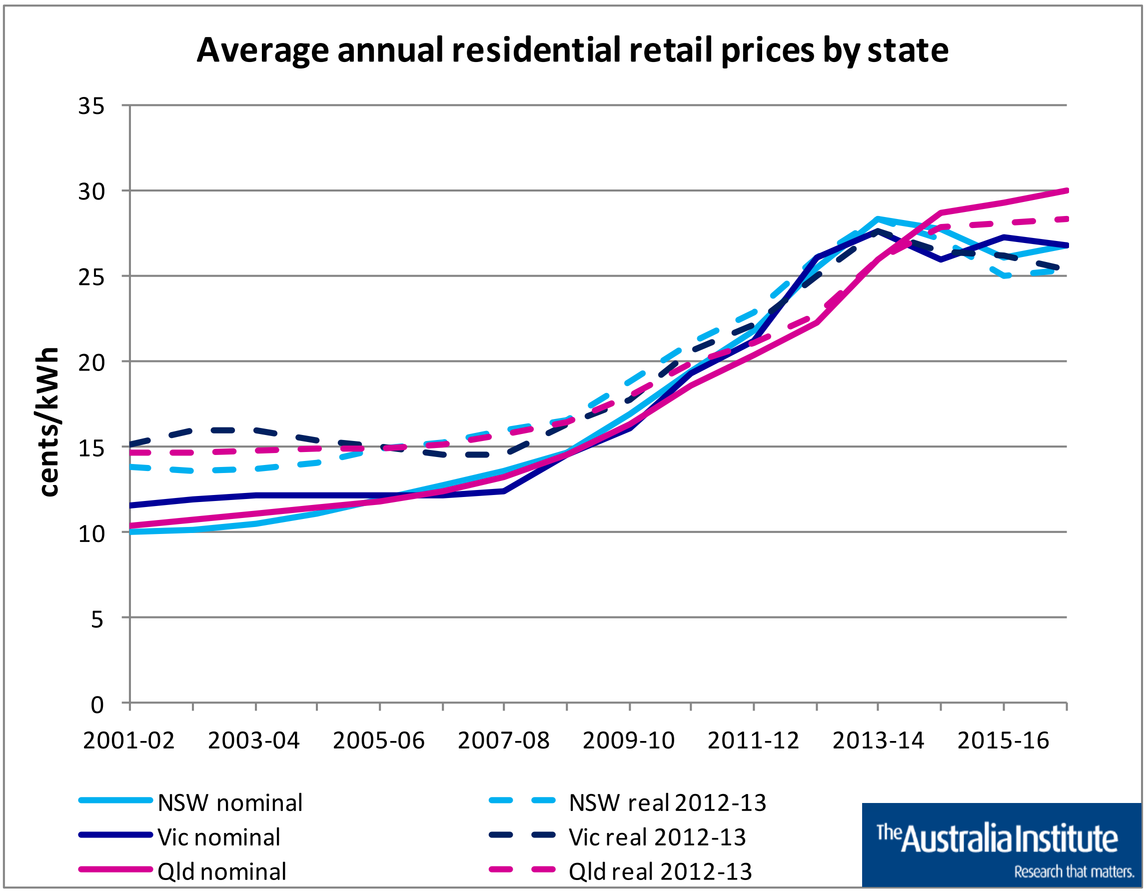
The July 2017 issue of NEEA Electricity Update examined the contribution of rising wholesale prices to the retail price increases now being seen by consumers across the NEM. In this issue we go back a few years to look at the contribution of increases in the network (transmission and distribution) component of costs.

These cost, components are the largest contributor to prices for all except very large industrial consumers, though wholesale prices are now catching up. Prior to this year, network costs were by far the largest contributor to the dramatic increase in electricity prices. In the 2016 edition of the AEMC's annual *Residential Electricity Price Trends* report it was estimated that transmission and distribution costs accounted for the following part of the total price paid for electricity by a representative average residential consumer during 2016-17:

South east Queensland	11.95 c/kWh	45%
NSW	10.90 c/kWh	45%
ACT	8.06 c/kWh	42%
Victoria	12.36 c/kWh	45%
SA	13.52 c/kWh	42%
Tasmania	12.03 c/kWh	54%

Thus, for 2016-17, transmission and distribution costs made the highest contribution (54%) to the total average residential price n Tasmania, while in SA and the ACT the contribution was the lowest (42%). These shares have, however, varied somewhat in both absolute and relative terms in past years. Figure 4 shows how average residential electricity prices have changed since 2002 in the three largest NEM states, expressed in both nominal dollars (of the day) and real 2012-13 dollars. Prices increased somewhat faster in Queensland and NSW than in Victoria.

Figure 4



Sources: Calculated from Consumer Price Index data and AEMC 2013 Residential Electricity Price Trends Report

Figure 5

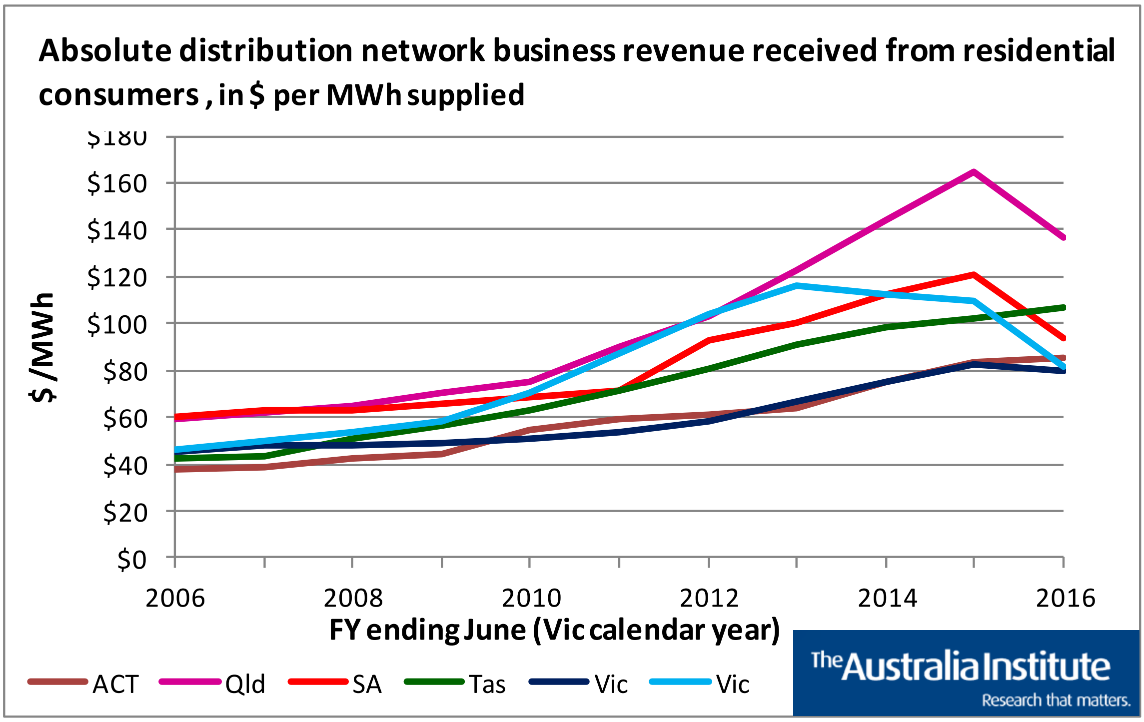
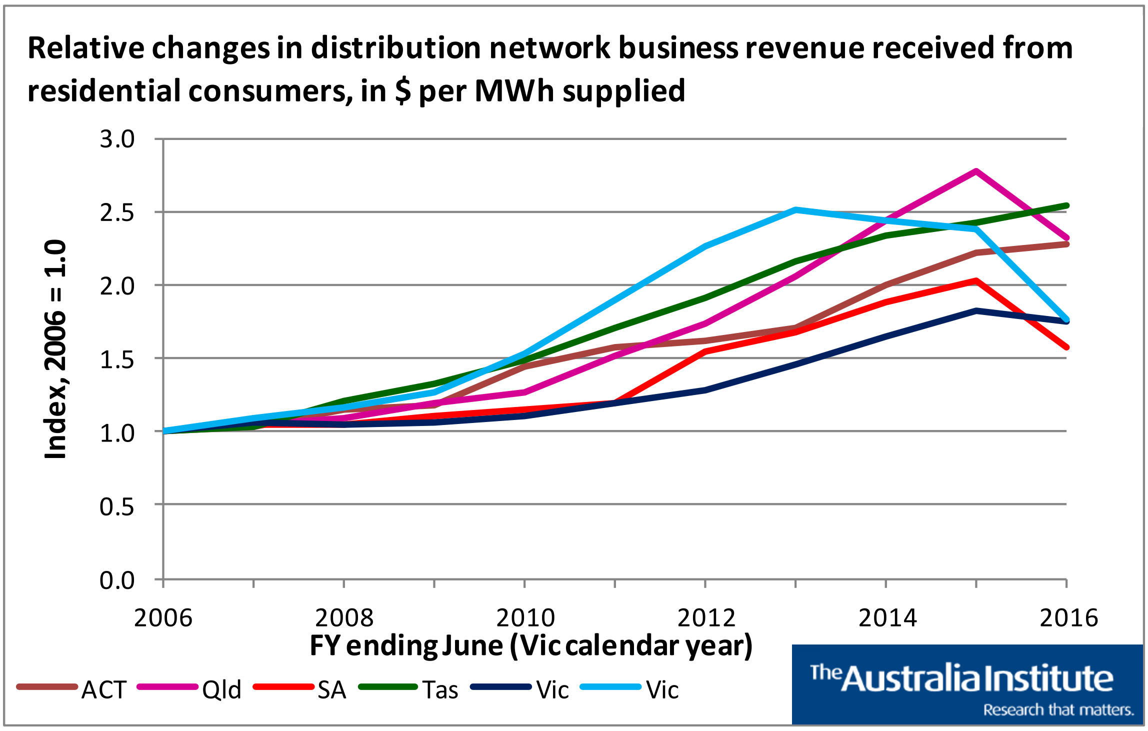


Figure 6



Source: Calculated from data contained in distribution business Regulatory Information Notice (RIN) reports to the AER

Figures 5 and 6 show, in absolute and relative terms respectively, the average revenue, per MWh supplied, received by distribution network businesses from residential consumers, in each state and each year since 2006. The Figures show that distribution network business revenues have increased much faster that total prices. Hence, network costs have not only increased as a share of total price, but also have been the main factor causing the price increases. Note that revenue received by distribution network businesses does not align exactly with the estimated network cost component of prices shown in Figure 4, because revenue also includes other components, notably the fixed daily connection charge.

Figure 7

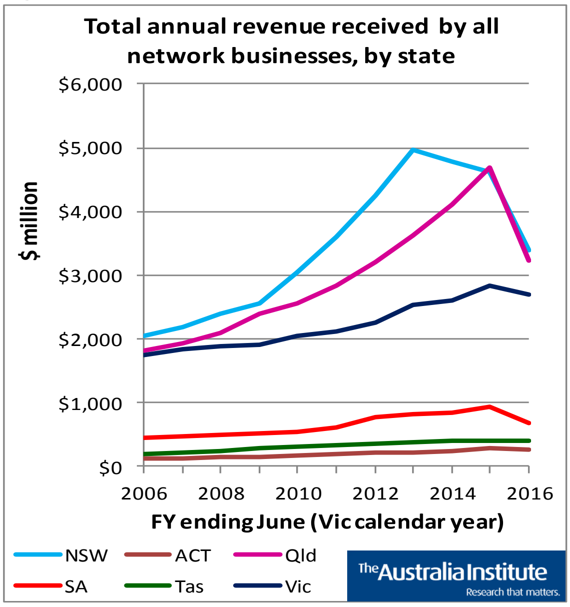
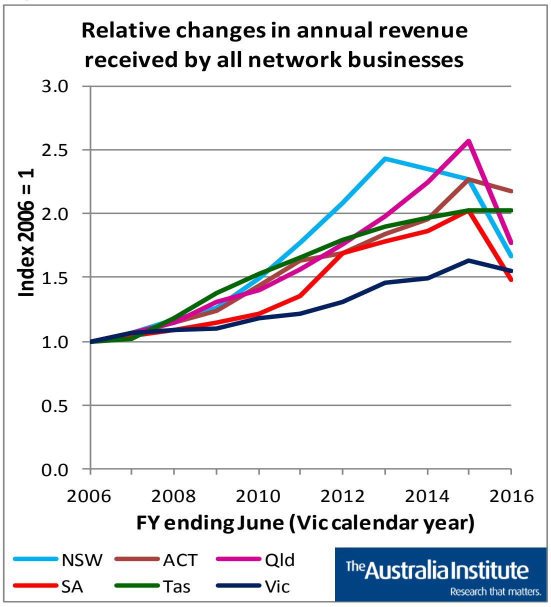


Figure 8



Source: Calculated from data contained in distribution business Regulatory Information Notice (RIN) reports to the AER

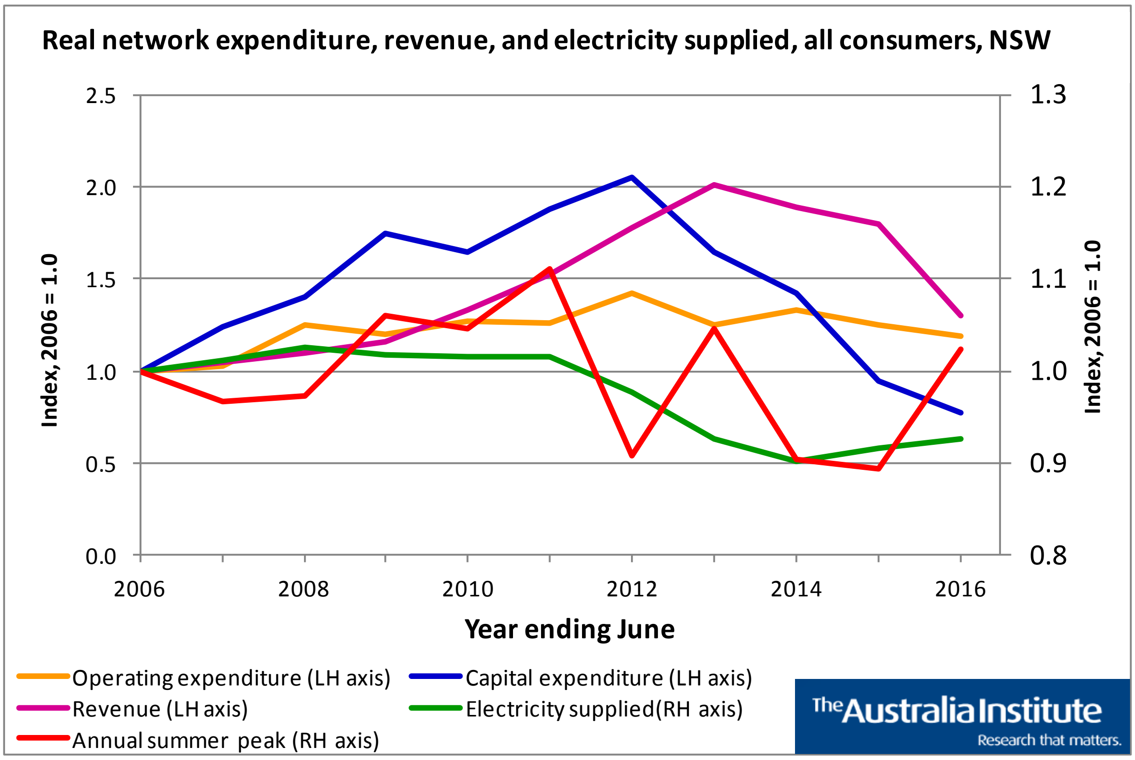
Figures 7 and 8 show the total combined annual revenue received from all consumers (residential and business) by both distribution network business in each state (which account for between 70% and 80% of the total revenue) and transmission businesses. It can be seen that, firstly, the rate of increase is much the same as the increase in revenue received from residential consumers alone and, secondly, that revenue of the businesses in NSW and Queensland is considerably higher than the revenue of the businesses in other states, and also increased much faster, particularly over the years from 2010 and 2013.

Revenue received by network businesses is used to cover their operating costs and also to service the capital which they invest. Figure 9 shows total key trend data since 2006 for the four NSW network businesses – Transgrid (transmission), and Ausgrid, Endeavour Energy and Essential Energy (distribution). Revenue and expenditure are expressed in real dollars, whereas the data in Figures 7 and 8 are in nominal dollars, which is why growth in expenditure and revenue appears slightly slower in Figure 9.

The Figure shows that annual operating expenditure increased by a factor of about 1.4 between 2006 and 2012, while annual capital expenditure more than doubled over the same period. By contrast, the quantity of electricity supplied to consumers over the whole year, measured in energy units (TWh), increased by less than 2% up to 2011, and since then has fallen away to be over 9% below the 2006 level. The annual peak trading interval (30 minute) demand, measured in power units (MW), increased faster up to 2011, but since then has also fallen away.

In some years, including, most recently 2012 and 2015, peak demand in the NSW region of the NEM is higher in winter than in summer. However, peak summer demand is usually more challenging for system operation, because the efficiency of both generation (including both thermal and renewable generation other than hydro) and transmission is lower at high ambient temperatures. For these reasons, forecast peak demand is a key driver of capital expenditure to increase supply capacity.

Figure 9



Source: Calculated from data contained in distribution business Regulatory Information Notice (RIN) reports to the AER

The most striking feature of Figure 9 is the change in the trend of both annual energy and peak demand after 2011, followed by a change in the trend of expenditure one year later. There is a further delay in the change of revenue, mainly because of the way the regulatory framework allows network businesses to earn a guaranteed rate of return on their total approved capital expenditure. The total value of historic approved capital expenditure, net of depreciation, is termed the Regulatory Asset Base (RAB). In NSW this continued to increase up until 2014-15, because of the legacy of very high capital expenditure over the years up to 2012. Since return on investment accounts for more than half the total revenue of electricity network businesses (AER, *State of the Energy Market May 2017*, Figure 3.3), continuing high RAB means continuing high revenue and hence continuing high prices for electricity.

Why did capital investment increase so much during the period up to 2012?

Figure 10

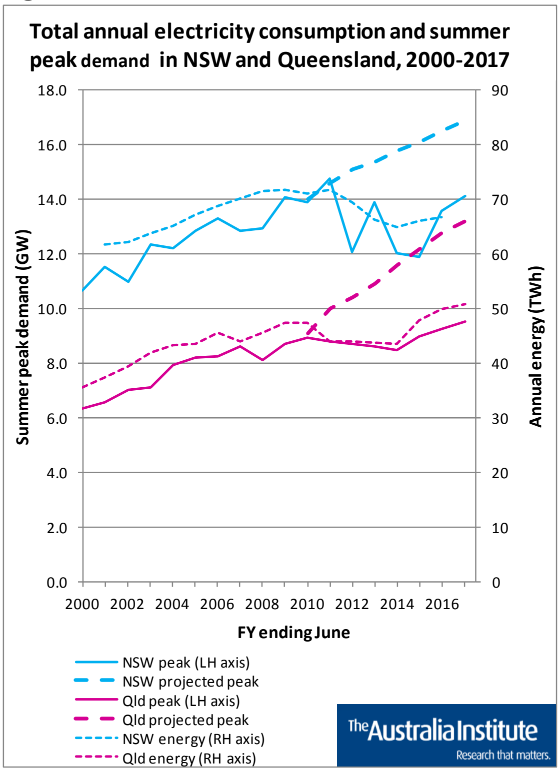
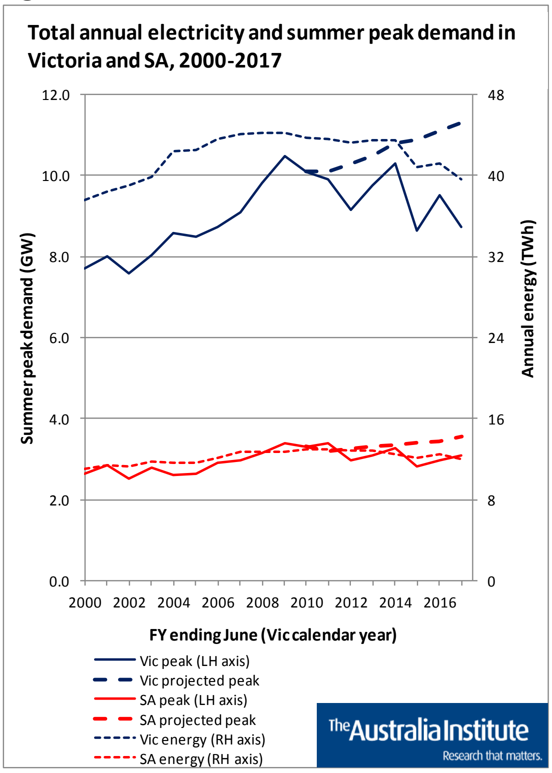


Figure 11



Source: Data extracted from EnergyGas Australia (Australian Energy Council), various past issues

The main reason is illustrated by Figures 10 and 11, which show annual electrical energy consumer and annual summer peak demand in each of the four mainland NEM regions (states). The Figures show large gaps between actual and future annual peaks as projected by AEMO in its 2011 *Statement of Opportunities* document. These expectations, combined with lack of institutional support for demand side measures which could have helped to reduce peak demand, allowed the network businesses to gain regulatory approval to make massive investments to increase supply capacity so as to be able to meet the projected extreme peaks. As it happened, AEMO subsequently realised that demand has ceased to grow in mid 2010, and in March 2012 issued revised and much lower projections of future demand for electricity. By then, however, much of the approved expenditure on additional capacity had already been incurred by network businesses.

Comparison of Figures 10 and 11 shows that the 2011 projections of future peak demand increases were higher for NSW and Queensland than for Victoria and SA. This difference goes some way to explaining why network costs and revenues have increased faster in NSW and Queensland than, in particular, Victoria.

Unfortunately, the overwhelming majority of the excess investment was directed towards increasing the capacity of networks to deliver a one-way flow of electricity from large, centralised power stations to consumers. At the time this investment was approved, distributed generation mainly took the form of industrial cogeneration, was not large and was hardly growing. Rooftop PV was negligible. That situation is now rapidly changing and distribution networks need to make new and different types of investment to allow two-way flow of electricity during the middle of the day in many parts of their networks. However, the need for such investment will be significantly affected by how much battery capacity is installed on-site with rooftop PV system; more battery capacity will mean less need for network upgrades. How to ensure that necessary changes are made to networks, while avoiding the over-investment mistakes of the past, is one of the many challenges facing policy makers and the electricity industry today.

Finally, it will be noted that the downturn in network business revenue seen in Figures 7, 8 and 9 is not reflected in the network cost component of consumer prices for electricity. This is largely a consequence of the steadily falling average demand per customer, occurring with both residential and business consumers. Residential consumption per customer fell, between 2009 and 2016, by 22% in Queensland, 17% in NSW, and around 15% in Victoria and SA. What consumers ultimately require is not electricity per se, but the services which electricity can deliver. What ultimately matters to household budgets in not the price of each kWh of electricity purchased but the total annual cost of the electricity they have to buy to obtain the services they require. Policy responses to high electricity prices should pay more attention to how consumers can be helped to use less electricity, by using it more efficiently to achieve the level of services they require.